ENERSOLVE DEMONSTRATION PROJECT

GREEN CREEK POLLUTION CONTROL CENTRE
OTTAWA, ONTARIO

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1.0 RAPPORT DE SYNTHESE

Le programme Enersolve, auquel est rattachée la présente étude, a pour but d'optimiser l'utilisation du mazout, du gaz et des combustibles résiduaires dans les procédés industriels. A ce stade du programme, il s'agit d'appuyer un nombre restreint de projets spécifiques de modernisation d'équipements, afin de fournir à l'industrie des renseignements sur les aspects économiques de la question.

Le travail a commencé à la fin du mois de décembre 1983. Une étude approfondie, visant à identifier l'équipement existant, a été effectuée au Green Creek Pollution Control Centre. Dans le même temps, les objectifs du projet ont été précisés au personnel du lieu. On a identifié et contacté un sous-traitant qui avait les qualifications requises pour effectuer les mesures nécessaires concernant les chaudières, et les essais ont été effectués en janvier 1984. Les données des essais sont présentées à l'annexe F, et les résultats au tableau A, page 7.

L'équipement de brûleur Raskin existant à ce moment-là (il a été remplacé récemment par du matériel neuf de la même marque) a donné des résultats d'essais favorables. Tout en brûlant les gaz de boues, le matériel a fourni les rendements suivants: à feu doux (charge de 25%), le rendement thermique était de 65%; à feu moyen (charge de 50% et 75%), le rendement était de 71-72%; à feu élevé (charge de 100%), le rendement thermique était de 75%.

Deux éléments importants ont été identifiés pour l'amélioration du rendement thermique:

i) de nouvelles commandes de chaudières comprenant des brûleurs et des appareiliages de commande et de réglage des brûleurs;

ii) et des récupérateurs de gaz de cheminées (économiseurs).

Le coût total de ces améliorations est évalué à 320 000 dollars, et la période de récupération des frais à 9 ans (voir section 4.3 pour les détails).

Les honoraires d'ingénierie, pour la mise en oeuvre du programme à cet endroit, sont évalués à 35 000 dollars.

1.0 EXECUTIVE SUMMARY

The Enersolve Program, under which this study was performed, is concerned with increasing the efficiency of utilization of oil, gas and waste fuels in industrial processes. This stage of the Enersolve Program is intended to support a limited number of site-specific retrofit projects as a means of documenting for industry the economics of such retrofit projects to older equipment.

Work commenced on the project in late December, 1983. An in-depth field indentification survey of existing equipment was made at the Green Creek Pollution Control Centre. At the same time, the aspirations of the project were detailed to the staff of the Pollution Control Centre. A sub-contractor, who had the capabilities to conduct the necessary boiler measurements, was identified and contacted. The tests were performed during January, 1984. Test data is presented in Appendix F. The results are presented in Table A, page 7.

The existing Raskin burner equipment at that time (recently has been replaced with new Raskin burner equipment) provided favourable test results. While firing the sludge gas, the following efficiencies were obtained: at low fire (25% load), the resulting thermal efficiency was 65%; at medium fire (50% and 75% load) the thermal efficiency was 71-72%; and at high fire (100% load) thermal efficiency was 75% .

To improve the thermal efficiency, two major items were identified which are: i) new boiler controls, which included burners and burner trim controls; and ii) stack economisers. The total cost for these improvements is estimated at $320,000. The payback for these improvements has been estimated to be 9.0 years. This is detailed in Section 4.3.

The associated engineering fees for full implementation of the program to this site are estimated to be $35,000.

2.0 INTRODUCTION

In response to a Request for Proposal to apply the EMR CANMET Enersolve Program, our firm identified an acceptable unit, owned and operated by the Regional Municipality of Ottawa-Carleton (RMOC), at the Green Creek Pollution Control Centre in Ottawa, Ontario. The RMOC expressed their interest in the program and offered their full co-operation in such a study.

A contract for assessment of the program was granted to BFH/Shawinigan and further identification was carried out during a site visit where up-to-date operating conditions and characteristics were discussed with the company representatives.

Our firm acknowledges the participation of Blanchfield Thermal Services for the boiler testing. The on-site boiler staff, was co-operative in supporting tradesmen during the testing period. We also wish to thank the Pollution Control Laboratory staff, for providing their services of gas analysis.

3.0 TECHNICAL DISCUSSION

3.1 Boiler Identification - Preliminary Visit

For the purpose of identifying an acceptable unit, a preliminary visit to the Green Creek plant was made on August 29, 1983 when the application of the program was discussed with the Owner's representatives.

The report and assessment done during that visit is presented in Appendix A of this report. At a later date, it was decided to conduct our assessment for the Enersolve Program on No. 2 Waste Fuel Boiler.

3.2 No. 2 Boiler and Auxiliaries Identification - Site Survey

A detailed identification of Unit No. 2 was made by the consulting engineer during a site survey on December 22, 1983. Operation was also discussed with the operators to identify specific problems and conditions. The results of the findings are presented in Appendix B for the following items and/or components:

.1 Boiler Identification
.2 Fan Details
.3 Gas Burners
.4 Boiler Controls
.5 Boiler Feedwater Pumps
.6 Steam Meters
.7 Gas Meters
.8 Boiler Stack
.9 Miscellaneous Components.
.10 Factory Test Results for Efficiency.

3.3 Boiler Efficiency Test Firing Natural Gas

During 1983 the RMOC, in an attempt to reduce operating costs and improve operations, decided to convert the two boilers at Green Creek from oil to natural gas. Oil would be retained on site as an ultimate stand-by fuel. Sludge gas would remain as the primary fuel, and natural gas would become the main standby fuel. The new burner equipment which would be installed was developed by Raskin. It would have the capability of firing all the necessary fuel types. During the actual conversion, technical problems arose with the delivery of natural gas. The quantity of gas required was 735 m^3/hr, but only 565 m^3/hr could be obtained. The conversion on Boiler #1 was permitted to proceed with the understanding that Boiler #2 would fire either sludge gas or oil for the winter season. At an appropriate time in the spring, the technical problems would be corrected and the conversion completed.

At this attempt to convert from oil to natural gas, a preliminary boiler efficiency test was conducted on Boiler #2 while firing natural gas. Results of this test are presented in Appendix C for information only. This will provide a rough judgment on the comparison of firing natural gas to sludge gas.

3.4 Sludge Gas

Appendix D contains a summary of gas analysis conducted by the Regional Pollution Control Lab over a six-month period. The average heating value for the gas is 22.38 MJ/m^3. Normal natural gas, usually is in the range of 37.13 MJ/m^3. The interesting aspect of this sludge gas is the lack of impurities, namely sulphur components, and the high levels of carbon dioxide. To illustrate where the sludge gas comes from, refer to Figure 1.

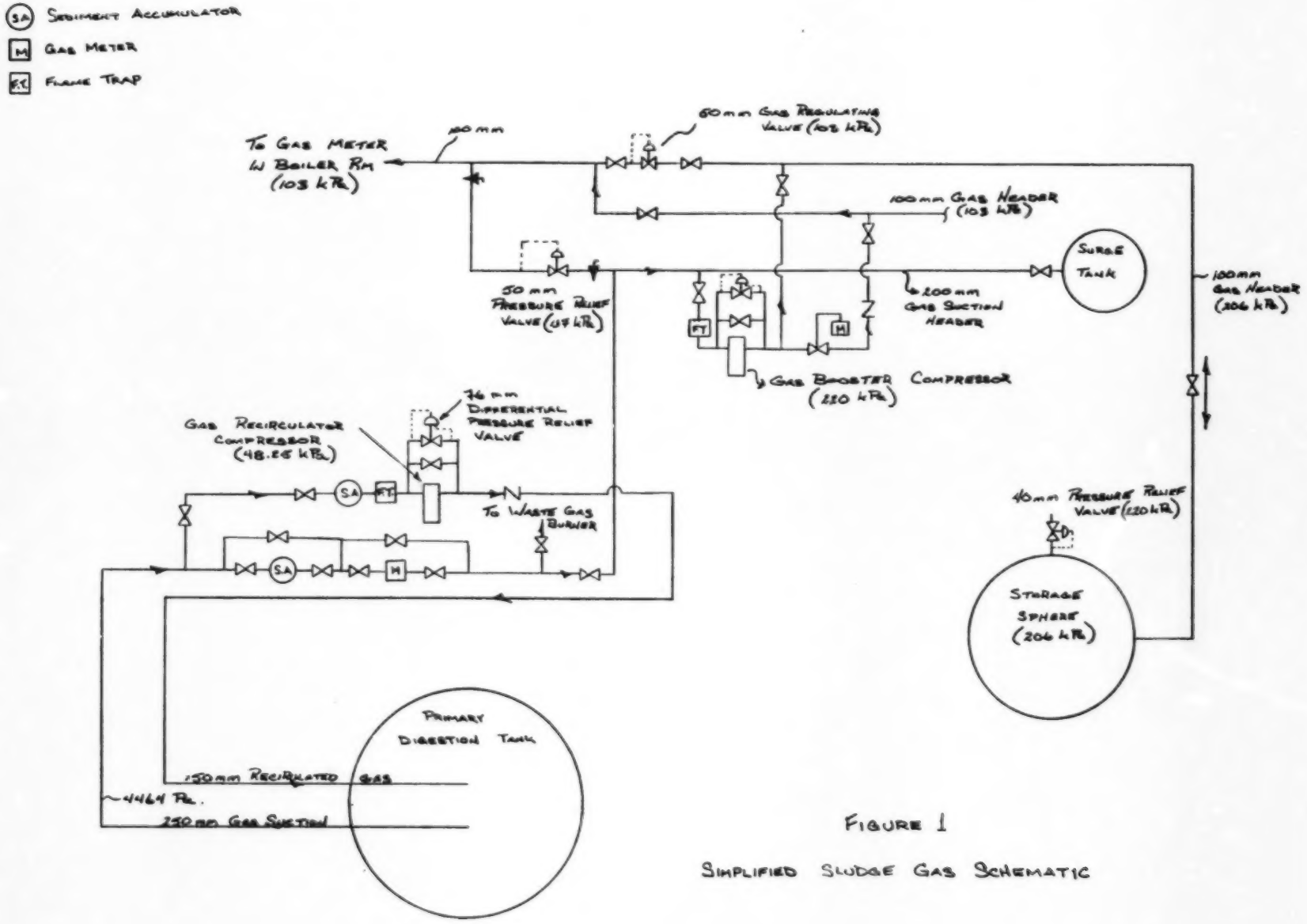


FIGURE 1

SIMPLIFIED SLUDGE GAS SCHEMATIC

3.4 Sludge Gas (cont'd)

The entering sludge from the City sewer lines, after being screened which removes the larger debris, is mixed with a coagulant and allowed to settle in the primary digestion tanks. It is at this point the sludge gas is formed. By the use of compressors, the gas is removed from the head space in the tank. Some of the gas is recirculated back to the digestor tanks, while the remainder is either stored in the sphere or used by the boilers. Excess gas is flared.

3.5 Efficiency Calculation

The ASME Power Test Code methodology for calculating boiler efficiency was used. This methodology has been summarized and simplified in a book entitled "A Combustion Handbook for Canadian Fuels, 1973". Volume 2 of this series has a set of graphs specific to gaseous fuels of Canada. It was with the aid of this book and the people at the Canadian Combustion Research Laboratory that the work was completed. By providing a gas analysis of the sludge from the two days of testing, specific curves were developed by a computer at the Laboratory. These curves are presented in Appendix E. Also included in Appendix E are sample calculations for the 25% load evaluation.

To calculate the heat loss due to radiation and convection by the boiler outer skin, the ABMA curve was used. This family of curves is presented in Appendix E. The number of cooled walls used was zero.

3.6 Boiler Testing Firing Sludge Gas

During the arrangements for conducting the tests, it became apparent that it would take two days. The test days were scheduled for January 26 and January 31, 1984. The time spread

3.6 Boiler Testing Firing Sludge Gas (cont'd)

was to accommodate Blanchfield Thermal Services and Green Creek Pollution Control Centre staff. Arrangements were also made with Mr. Shea of the Pollution Control Centre Laboratory to conduct gas analysis on these two days. This would provide precise data for heat loss calculations. These particular gas analyses are presented in Appendix D, Table 2. The data sheet presents a summary of the analyses, as well as the calculated heating value.

The flue gas data was obtained by utilizing two different sets of equipment. The main piece of equipment was an electric device developed by R.A.B. Debesco Ltd. The back-up piece of equipment was the standard Bacharach Fireye Test Kit. The R.A.B. Debesco Unit, Model O-C, uses a small pump to draw a gas sample from the stack. At the end of the stack probe is a sheathed type K thermocouple to measure the gas temperature. The gas sampled is dried by passing it through a descinatant cell and the oxygen in the sample is then measured by an electrochemical cell. With the Model O-C, a measurement is also taken of the CO/combustibles by an electrochemical cell. The specifications for R.A.B. Debesco, Model O-C unit are presented in Appendix F.

Table A, as presented on page 7, is a summary of the resulting thermal efficiency for the boiler. At 28% load the resulting thermal efficiency is 63.8%; at 54%, it is 72.4%; at 74%, it is 71.3%; and at 100%, it is 74.25%. Test data was re-evaluated for the 50% and 75% loads, to ensure no mistake had been made. The only explanation that can be presented to account for the increased thermal efficiency at 50% is that the boiler had been firing all night at that particular load. Whereas, for 75% load, which was conducted on the first day, there was a time span to allow the boiler to warm up from the first test at 28%

Table A

Summary of Boiler Testing

	DAY 1 TEST 1	DAY 2 TEST 1	DAY 1 TEST 2	DAY 2 TEST 2
Percent Load	25%	50%	75%	100%
Actual Evaporation (lb/hr)	2800	5400	7400	10 250
Pressure (psig)	85	84	83	79
Steam Temp (°C)	163	162	162	160
Feedwater Temp (°C)	96	98	102	100
Room Temperature (°C)	16.5	21	18	21
Stack Net Temp (°C)	190	236	276	290
Excess Air	133%*	64%*	43%*	20.5%*
Total Combustion Air	233%*	165%	144%	125%
Fuel Fired	Sludge	Sludge	Sludge	Sludge
HEAT LOSSES				
Dry Gas	15.3*	12.0	13.0	10.75
Hydrogen	11.5*	10.5	11.4	10.9
Unburned Combustible	0.4*	0.11*	0.16*	0.19*
Radiation	7.5	3.2	2.5	2.20
Unaccountable	1.5	1.5	1.5	1.50
TOTAL	36.2	27.3	28.56	25.5
Thermal Efficiency (100% - Total)	63.8	72.7	71.4	74.5

* Hand Calculation

3.6 Boiler Testing Firing Sludge Gas (cont'd)

load. This would tend to indicate that the longer a boiler is permitted to operate at a constant load, the better the resulting thermal efficiency.

With regard to the actual conducting of the four tests, no major problems were encountered. There was no need to perform a blow-down during any of the tests due to the almost completely manual control of the process equipment. The flame during all tests was even and consistent in colour - a slight off-blue.

3.7 Conclusion of Tests and Results

Based on the tests and observations of operations, we have reached the following conclusions:

3.7.1 As shown in Table A, the thermal efficiency ranges from 64% at low fire to 74% at high fire.

3.7.2 Even though excess air was provided, as shown in Table A, a CO loss occurs in all four tests. This is believed to be caused by a flame impingement on the wall of the water tubes.

3.7.3 By trimming the excess air to a minimum of 20%, for safety factors do not wish to go lower, boiler efficiency would improve. At low fire the improvement would be about 10%, whereas at high fire the improvement would be about 2%. The normal operating condition for this boiler is 50 to 75%. In this range, the efficiency improvement is about 3%.

3.7.4 The comparison of the dry flue gas and hydrogen losses of Boiler #2, while firing either natural gas or sludge gas, is presented in Table B on the next page.

3.7 Conclusion of Tests and Results (cont'd)

Table B

Load	Losses		Difference
	Nat'l	Sludge	
100%	22.4	21.6	0.8
75%	20.6	24.2	-3.6
50%	20.2	22.4	-2.2
25%	18.3	26.8	-8.5

This comparison shows little difference in the fuel used for loads above 50%. At low fire, it clearly shows that the sludge gas is not a wise choice. On closer examination it is to the dry flue gas losses that a major portion of the difference can be attributed.

3.7.5 At 75% load, the net stack temperature was 277°C. The steam temperature at this load was 162°C. Therefore, a stack economizer could be installed to reduce the stack temperature from 277°C to 165°C. This temperature reduction will provide enough energy to raise the present condensate return from 65°C to 92°C, before entering the deaerator. This will result in a 5% increase in thermal efficiency.

3.7.6 The sludge gas as detailed in Appendix D, Table 1, indicates an average heating value of 22.38 MJ/m^3. The daily variance of this sludge gas is $\pm$4.2%, and the maximum range is $\pm$15%. Seldom would this maximum fluctuation of the heating value occur over a period of one day. Therefore, relatively consistent efficiencies can be expected.

4.0 RECOMMENDATIONS FOR RETROFIT AND COST/BENEFIT ANALYSIS

4.1 Recommendations

From the conclusions presented in Section 3.7, two specific areas of retrofit are suggested which are: Combustion Control and Boiler Improvements.

Combustion Control at present, is achieved by a standard parallel matrix with one boiler master. This is quickly verified by the present burner instrumentation, presented in Appendix B, as well as the changing total combustion air percentage shown in Table A. The current boiler master operates from the steam header pressure, which is set to maintain 550 kPa. Any deviation from this set point alters the firing rate of the boilers accordingly (increase in steam pressure causes a decrease in firing rate, and vice versa). A further aggravation to this type of control is that both boilers fire at similar rates. With the proposed new master, one boiler will be allowed to load to the 80% mark before the second unit begins to fire. The new controls would consist of one plant master, two Conserver I packages, two new burners and two new steam meters

The purpose of the new plant master is twofold. The first requirement is the staging of the identical boilers; the second is compatibility with the Conserver I package. The Conserver I package utilizes a solid state oxygen analyzer in the flue gas. By measuring the oxygen content in the flue gas, the Conserver calculates the proper air/fuel ratio. In the case of sludge gas, this ratio is approximately 6.5 to 1; for natural gas, this ratio is 10 to 1. Therefore, the output of the Conserver package regulates the total combustion air to the boiler.

With installation of the new Raskin burners (specification is presented below) new burners of the appropriate size will now have to be installed.

Model	LAL 6 - 7FA
Serial	POG - 109
Oil	# 3
Gas	Natural/sludge
Oil	max. 75 IGPH (340 L/HR)
	min. 15 IGPH (68 L/HR)
Gas	max. 18,000 cfh (510 m^3/HR)
	min. 2,000 cfh (56 m^3/HR)
Oil pressure	15 psig (342 kPa)
Gas pressure	5 psig (34.2 kPa)
Gas burner pressure	inches W.C. 55/25 (13.6/6.2 kPa)
(sludge/natural)	4/4 (1.0/1.0 kPa)
Manifold gas pressure	140 inches W.C. (34.8 kPa)

The replacement Raskin burners reduce the boiler output from the original 4545 kg of steam per hour to 3500 kg of steam per hour. Therefore, burners will have to be re-sized to maintain the original rating of the boiler.

In conjunction with these changes, to improve the present boiler plant operation it is also suggested that two new steam meters be installed. By replacing the existing steam meter equipment, accurate steam pressure flow can be monitored and recorded.

Boiler Improvements will also have to be done in association with the control changes. As previously mentioned in Section 3.7.5, excess energy is available in the flue gases. The 75% load demonstration was provided due to the fact that this is typical loading of the two boilers. Repeating the calculations for 50% and 100% load, the following results, in theory, can be obtained:

Load (%)	Present Net Stack Temp	Net Stack Temp with Economizer	Present CRT *	CRT with Economizer
50	236°C	165°C	65°C	78°C
75	277°C	165°C	65°C	92°C
100	290°C	165°C	65°C	101°C

* CRT = Condensate Return Temperature

With the proposed application of stack heat recovery to the condensate return before entering the deaerator, it therefore becomes a requirement to replace the deaerator. The present vertical tray-type deaerator is twenty years old and is becoming increasingly difficult to maintain. It is doubtful that this unit will be capable of compensating for the proposed higher condensate return temperature.

4.2 Costs

The Bailey Control Package as described in Section 4.1, which includes two Conserver I packages, a new plant master and two new steam meters, is estimated to cost $160,000 installed. The two new gas burners will cost approximately $50,000 installed. The new deaerator is estimated at $60,000 installed. The two stack economizers, installed, are estimated to cost $50,000 which includes the necessary peripherals such as piping and controls.

Therefore, the retrofit capital costs for Green Creek are estimated to be $320,000, plus associated engineering costs estimated at $35,000 for a total cost of $355,000.

4.3 Benefit Analysis

Since the boiler plant's normal operation is in the 50-75% load range, Table C shows the predicted results of the proposed changes on the thermal efficiency.

Table C

Predicted Changes to Thermal Efficiency

Item	Present	Improvements	
		Air Trim	Economizer
50% Load			
Net Stack Temperature	236°C	236°C	165°C
Total Combustion Air	165%	120%	120%
Dry Flue Gas Losses	12.0%	8.5%	6.0%
Hydrogen Losses	10.5%	10.5%	9.9%
Total	22.5%	19.0%	15.9%
75% Load			
Net Stack Temperature	276°C	276°C	165°C
Total Combustion Air	144%	120%	120%
Dry Flue Gas Losses	13.0%	10.5%	6.2%
Hydrogen Losses	11.4	11.4	10.5
Total	24.4%	21.9%	16.7%

Therefore, the best possible improvement to thermal efficiency at 50% load is 6.6% (22.5 - 15.9); and at 75% load, it is 7.7% (24.4 - 16.7). This is assuming that similar conditions such as boiler room temperature and sludge gas heating value are present.

Table D summarizes the fuel type, associated volume and energy input to Plant.

Table D

Total Energy Consumed

Fuel	Volume	Energy	Percentage
sludge	3,131,000 m^3	70.075 TJ	93.0
natural gas	56,930 m^3	2.125 TJ	2.8
oil	83,090 L	3.182 TJ	4.2
	Total	75.381 TJ	100

The present thermal efficiency in the now normal operating range of the Boiler Plant is 72%. By applying 7% improvement to the thermal efficiency (from Table C), the Plant's available energy while firing sludge gas would rise from 50 045 GJ (70.075 x 0.72) to 55 360 GJ (70.075 x 0.79). This increase of 5315 GJ is comparable to the total amount of energy while burning natural gas and oil at the Green Creek Plant during 1983. Using this comparison, the estimated dollar saving could be $35,250.

If all measures are applied for the total expenditure of $320,000, the possible payback period to RMOC could be as low as 320,000/35,250 = 9.0 years. The RMOC guideline for energy management payback periods is dependent on where the programme would be applied and what the benefits are. The maximum payback that RMOC would consider is twenty years.

Ideally, the best situation at Green Creek would be not to burn natural gas and oil. This is not possible due to the heavy water run-off in the spring. Anytime the water-to-sludge ratio is high, production of the methane gas in the primary digestion tanks drops off. Therefore, not only in spring but over any extended period of time with heavy rainfall, this situation can occur.

4.4 Cost Estimates for Project Engineering

The total engineering fees that will be charged for plans and specifications, supervision and nine-month monitoring period phase of the retrofit are $35,000. This allows 75% for the design phase and 25% for the supervision and monitoring phase.

The anticipated time frame for the project implementation is three months for the design stage, nine months for project implementation, and nine months for monitoring. Due to the continuous operation at Green Creek, this schedule could require

a six month extension for implementation if the start of the construction phases could not coincide with the yearly shutdown of the Plant in the Spring due to the heavy water run-off.

5.0 GENERAL CONCLUSION AND DISCUSSION

While this report was being finalized, the completion of the conversion from oil to natural gas was also finalized (work was completed in the first weeks of April).

At first appearance, the change of the burner equipment, according to the burner specification, does not appear to be that drastic. On closer review, it becomes apparent that the new burners derate the existing boilers by 25%. For this reason, as outlined in Section 4.1, "Recommendations", new burners have been included in the retrofit.

The present mode of operation is to run both boilers at partial loads. One can understand the need to operate in this fashion because of the process load, but looking at the situation of operating efficiency, it would be wiser to operate one boiler until its capacity was approached. Because the two boilers are of equal size, any load over 100% capacity of one must be shared, thus reducing overall operating efficiency.

The application of the Enersolve Program on industrial boilers has undoubtedly enhanced the need for proper combustion control equipment. Although the boilers have been working effectively while burning sludge gas, it was evident that improvement could be made. By applying the thermal efficiency method one could predict the amount of improvement in overall efficiency by limiting the amount of combustion air. Since good test data was obtained, applying the thermal efficiency method became easy.

By applying the retrofit measures, the quantity of fuel that could be saved would be equal to the total amount of the other fuels burned during the year 1983. If applied at other similar sites across Canada, this activity would reduce this particular industry's need for primary fuels.

APPENDIX A

A1. Boiler: Loads and Data

Boilers:	B-1 4545 kg/hr (10 000 #/hr)	B-2 4545 kg/hr (10 000 #/hr)
Fuel Types:	Natural gas Sludge gas No. 3 oil	No. 3 oil Natural gas Sludge gas

Loads and Data : 24-hour operation
: maximum boiler output 24.5 GJ/hr
: maximum process load 28.4 GJ/hr
: maximum miscellaneous 14.0 GJ/hr
: load diversity 50%

Sludge gas production rate: - 576 m^3/hr @ 6 kPa gauge
Storage tank volume: - 4250 m^3 @ 205 kPa gauge
Boiler sludge gas consumption rates:
minimum - 210 m^3/hr
maximum - 845 m^3/hr

A2. Report of Site Visit to Green Creek, Ottawa, Ontario

A2.1 The facility consists of two (2) Dominion Bridge water tube boilers which utilize Raskin combustion equipment. Each unit is rated for 4545 kg/hr of steam at 550 kPa.

A2.2 Original installation in 1962 had the boilers firing on No. 3 oil and sludge gas. During the fall of 1983, work

A2. Report of Site Visit to Green Creek, Ottawa, Ontario

commenced on the total conversion of both boilers to fire on Natural Gas and sludge gas. Oil was to remain as a third alternative in case of emergency. Raskin combustion equipment is being used for the conversion. Presently Boiler No. 1 is capable of firing on Natural or sludge gas and oil. Presently incapable of completing the conversion on Boiler No. 2 further details are given in Section 3.3.

A2.3 Orifice plates were changed during August 1982 in the 152.4 mm steam main to compensate for 550 kPa operating pressure instead of 860 kPa, as initially installed.

A2.4 Steam meters are cleaned, adjusted and re-checked for accuracy, but have never been recalibrated since their original installation.

A2.5 Changes have been made to the original process and building heating loads, but there has not been any update or improvement in steam controls.

A2.6 New steam pipes and insulation has been installed in some locations, as well as new condensate receivers. In other areas steam pipe insulation is poor.

A2.7 After obtaining nameplate data, and conducting discussions with heat exchanger manufacturers, the maximum connected loads were found to be: building heat - 1583 KW; domestic hot water - 2305 KW; and process - 7888.9 KW; the maximum output of both boilers combined is 6805.6 KW.

A2. Report of Site Visit to Green Creek, Ottawa, Ontario

A2.8 The valuable data which will be obtained from this project will also be used in another ongoing project to expand both Plant and Process facilities. The combustion data will be utilized for better determination of co-generation equipment.

A2.9 The sludge gas heating value generally ranges between 20.54 MJ/m^3 and 24.25 MJ/m^3. The generally accepted value by Green Creek has been 22.38 MJ/m^3. Therefore, a rough calculated efficiency appears to be output/input times 100%.

$$= \frac{4545 \text{ kg/hr} \times 2.7 \text{ MJ/kg}}{845.0 \text{ m}^3\text{/hr} \times 22.38 \text{ MJ/m}^3} \times 100\% = 64.8\%$$

APPENDIX B

B1. No. 2 Boiler Identification

Make:	Dominion Bridge Ltd., water tube
Model:	Y2102
Heating Surface:	1283 square feet ASME

NOTE: Combustion service is done by Raskin, Montreal.

B2. Fan Details

Combustion Air Blower:
- supplied by Aerofoil, 1961
- F 151 HVA
- 3 HP, 550/3/60

B3. Combustion Equipment

Make:	Raskin Series "LAG-59" Console Combination Gas and Oil Burner Units
Model:	LALG-7FA
Serial:	POG-108
Fuel:	Sludge Gas No. 3 oil
Capacity - Oil:	maximum 75 IGPH (340 L/hr) minimum 15 IGPH (68 L/hr)
Capacity - Gas:	maximum 30 000 CFH (845 m^3/hr) minimum 7 500 CFH (210 m^3/hr)
Pilot:	Propane
Pressure at Inlet:	Oil 50 psig (342 kPa) Gas 5 psig (34.2 kPa)

B4. Boiler Controls

- Combustion controls by Fireye, type FP-2, model 1012, by Electronics Corp. of America (Canada) Ltd.
- Draft by Honeywell modutrol motor type M904E
- Excessive steam pressure is sensed by a Honeywell L404A
- Burner control is achieved by a Honeywell L91B

B5. Boiler Feedwater Pumps

- Three in parallel each rated for 20 IGPM at 228 ft. hd.
- Pump type is Arthur S. Leitch
- Motor: Leland Newman - 550/3/60
  - 3600 RPM
  - 7.5 HP

B6. Steam Meters

Bailey steam flow meters. Flanged orifice with chart output and integrated reading.

- Type DC 3651
- Office size 85.725 mm (3.375 in)

B7. Gas Meters (Sludge)

Rockwell with compensator, model Encorrector, type I. Pressure range 0 - 20 psig. Compensotor changes from 14.6 psi to 14.73 for atmospheric pressure.

B8. Boiler Stack

Hot gases are piped to the main stack which collects from both existing boilers without the use of induced draft fans. Downstream from each boiler, there are automatic motor actuated backdraft dampers.

B9. Miscellaneous

B9.1 Deaerator

- Is a vertical tray type mounted at boiler floor level
- Operating temperature is 115°C (240°F)
- Steam is supplied at 3 psi (20.6 kPa)

B9.2 Chemical Treatment

- Bird Archer
- 18 X 5-0 auto zeolite softener on water make-up

B9.3 Condensate Collection Systems

At various locations in the Plant are condensate receivers. From these receivers, the condensate is pumped to the deaerator, located in the boiler room.

B10. Results of Original Factory Test Before Installing at Green Creek

Boiler Room Conditions: 80°F
60% RH
29.92 inches of mercury
specific humidity: 0.013 lb/lb dry air

Sludge Gas Analysis: specific gravity: 0.85
BTU/ft3 at 60°F
30 inches of mercury - 591.5

Analysis:		
	CH_4	58.5%
	H_2	3.7%
	CO_2	28.0%
	N_2	8.0%
	O_2	1.8%
	TOTAL	100.0%

Test

Actual evaporation, lb/hr	10 000
Pressure at boiler outlet	80 psig
Steam temperature at boiler outlet	324°F
Feed temperature entering boiler	212°F

	OIL	GAS
Gas temperature (stack) °F	524	512
Excess air leaving boiler	15%	20%
Heat losses		
Dry Gas	9.28%	9.04%
Hydrogen and moisture in fuel	6.0%	11.70%
Unburned combustible	--	--
Radiation	1.75	1.75
Unaccountable	1.5	1.5
TOTAL	18.53	23.99

APPENDIX C

Boiler No. 2 Efficiency Testing
October 5, 1983
Firing Natural Gas

Gas Pressure Inches of Water	Pascal	% Load	Stack Temp °C	% O_2	Losses *		% Efficiency
					Dry Flue Gas	Hydrogen	
19	4731	100	286	3.15	10.4	11.95	74.0
18	4486	95	278	3.25	9.0	11.80	76.0
16	3984	84	273	3.40	8.8	11.80	76.4
14	3486	74	270	3.70	8.8	11.78	75.3
12	2988	63	260	4.40	8.7	11.70	75.6
10	2490	53	241	5.10	8.6	11.60	74.8
8	1992	42	228	5.00	7.3	11.45	76.3
5	1245	26	203	5.00	7.0	11.25	72.7

* These are major losses. The final % efficiency also includes radiation losses and unaccountable losses.

APPENDIX D

Table D1

Summary of Sludge Gas Variance over Six Months

	Date	Percentage (%)				Net Heating Value BTU/cu.ft.	Gross Heating Value BTU/cu.ft.	GHV MJ/m3	
		CH4	CO2	N2	02				
1	83-06-21	63.2	36.6	0.2	--	576.0	639.7	23.94	
2	83-06-17	61.4	37.5	1.1	--	559.6	621.5	23.26	
3	83-06-08	62.1	37.9	--	--	566.0	628.6	23.52	
4	83-06-02	59.3	40.7	--	--	540.5	600.3	22.46	
5	83-05-27	57.8	39.9	2.0	0.2	526.8	585.1	21.90	
6	83-05-17	60.0	39.7	0.3	--	546.9	607.4	22.72	
7	83-05-11	54.5	40.8	3.7	1.0	496.7	551.7	20.65	
8	83-05-04	64.1	35.5	0.4	--	584.3	648.9	24.28	
9	83-04-29	60.4	35.6	3.2	0.8	550.5	611.4	22.88	
10	83-04-19	59.4	40.6	--	--	541.4	601.3	22.50	
11	83-04-14	54.3	40.2	4.3	1.2	494.9	549.7	20.57	
12	83-04-06	56.8	42.9	0.3	--	517.7	574.9	21.51	
13	83-03-28	55.4	42.2	1.9	0.5	504.9	560.8	20.99	
14	83-03-24	59.1	40.5	0.4	--	538.5	598.2	22.39	
15	83-03-16	59.3	40.7	--	--	540.3	600.2	22.46	
16	83-03-09	60.5	38.3	0.7	--	551.2	612.4	22.92	
17	83-02-21	57.6	38.4	3.2	0.8	524.8	583.1	21.82	
18	83-02-15	57.8	39.6	2.0	0.6	526.6	585.1	21.90	
19	83-02-07	58.0	39.9	1.7	0.4	528.5	587.1	21.97	
20	83-02-01	60.4	39.0	0.6	--	550.3	611.4	22.88	
21	83-01-24	59.8	40.2	--	--	544.8	605.4	22.66	
						538.6	598.3	22.39	Average
1	83-05-05	58.6	36.7	3.7	1.0	534.1	593.2	22.19	Watt Cr*

* Watt's Creek is another RMOC Pollution Control Centre which produces a sludge gas. An analysis on Watt's Creek gas is presented here for information only.

APPENDIX D

Table D2

Summary of Sludge Gas on Test Days

	Date	Percentage (%)				Net Heating Value BTU/cu.ft.	Gross Heating Value BTU/cu.ft.	GHV MJ/m3
		CH4	CO2	N2	02			
1	84-01-26	62.8	37.2	--	--	572.7	635.5	23.78
2	84-01-26	62.9	37.1	--	--	573.6	636.5	23.83
3	84-01-26	63.3	36.5	0.2	--	577.3	640.6	23.97
4	84-01-26	63.1	36.6	0.3	--	575.5	638.5	23.90
AVERAGE		63.0	36.8	0.2	--		637.7	23.86
1	84-01-31	61.6	38.2	0.2	--	561.8	623.4	23.33
2	84-01-31	61.8	38.2	--	--	563.6	625.4	23.40
3	84-01-31	61.9	38.1	--	--	564.5	626.4	23.44
4	84-01-31	61.8	38.2	--	--	563.6	625.4	23.40
AVERAGE		61.8	38.2	--	--	563.6	625.4	23.40

APPENDIX E

SAMPLE CALCULATIONS

From gas analysis Appendix D for Day 1

$$CH_4 = 0.63$$
$$CO_2 = 0.368$$
$$N_2 = 0.002$$
$$1.000$$

Weight of carbon = (12.011 x 0.63) + (12.011 x 0.368) = 11.98
Weight of hydrogen = 4.032 x 0.63 = 2.54
Weight of nitrogen = 28.016 x 0.002 = 0.05
Weight of oxygen = 32 x 0.368 = 11.77
Total weight of fuel = 26.34

Therefore, ultimate analysis of fuel is:

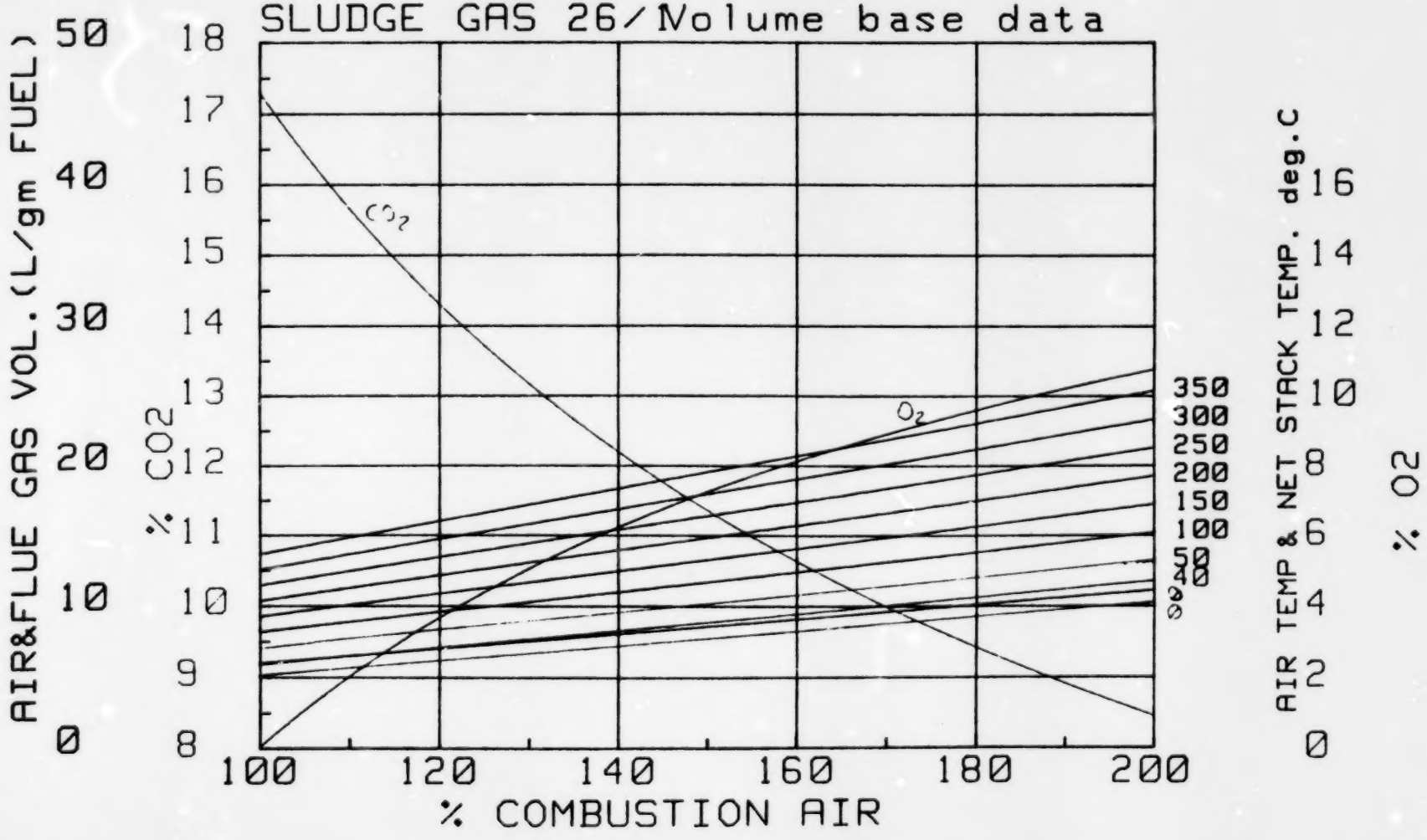
carbon	11.98/26.34	=	0.455
hydrogen	2.54/26.34	=	0.096
nitrogen	0.05/26.34	=	0.002
oxygen	11.77/26.34	=	0.447
			1.000

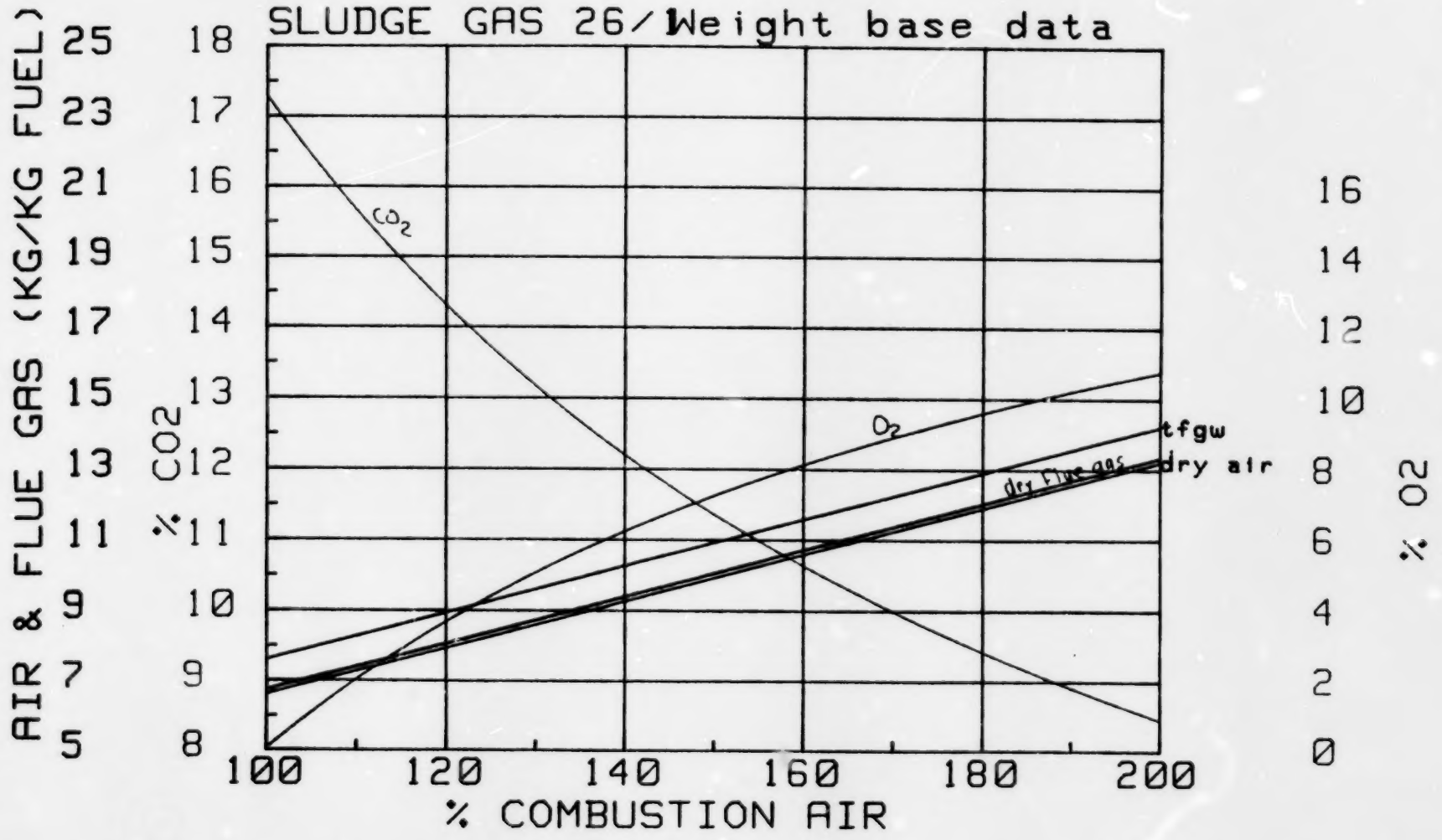
Before calculating the stoichicmetric air requirement, the weight to volume ratio be calculated:

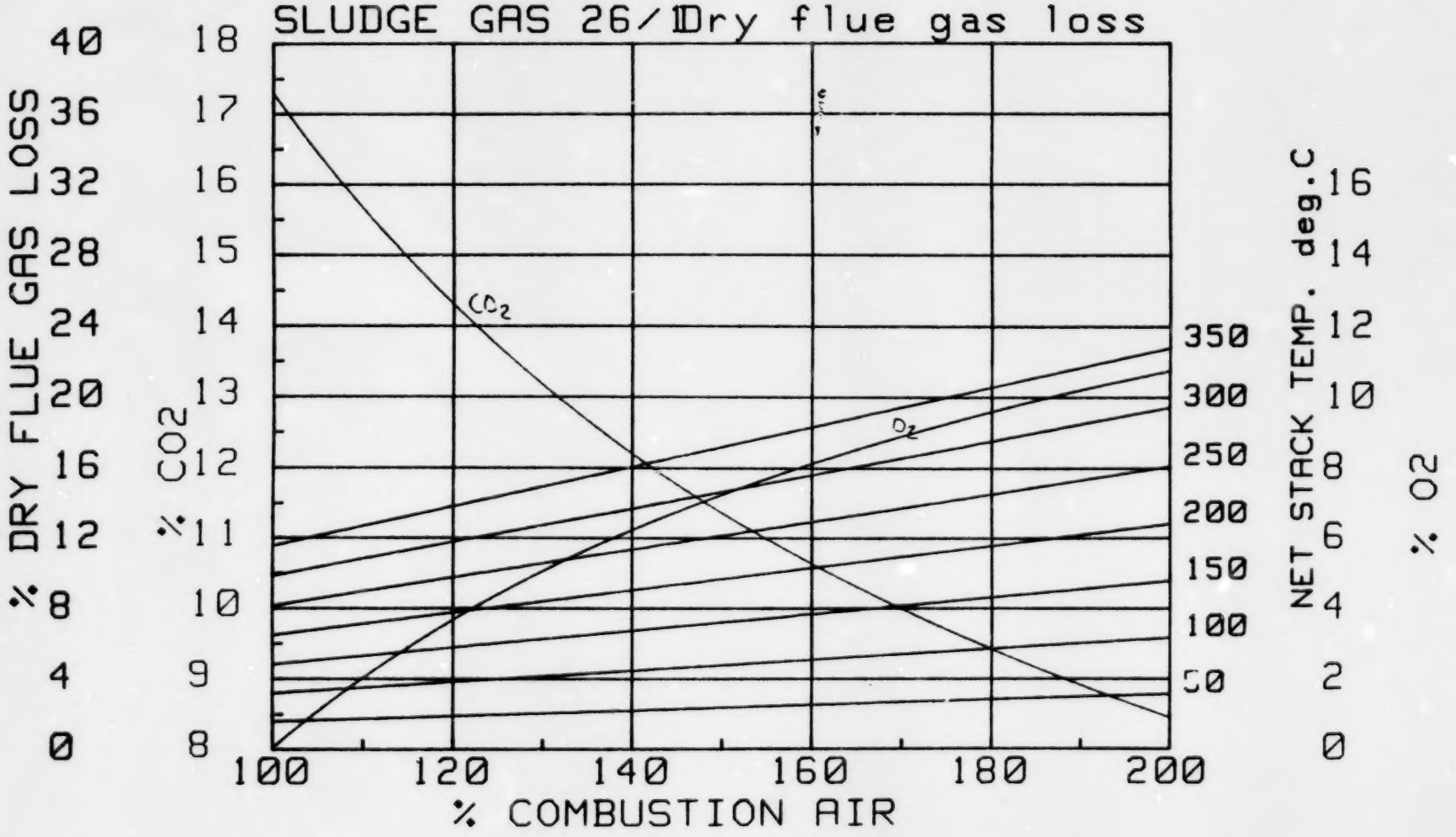
lb/cu.ft. = (0.63x0.04242) + (0.368x0.1170) + (0.002x0.07439)
= 0.069

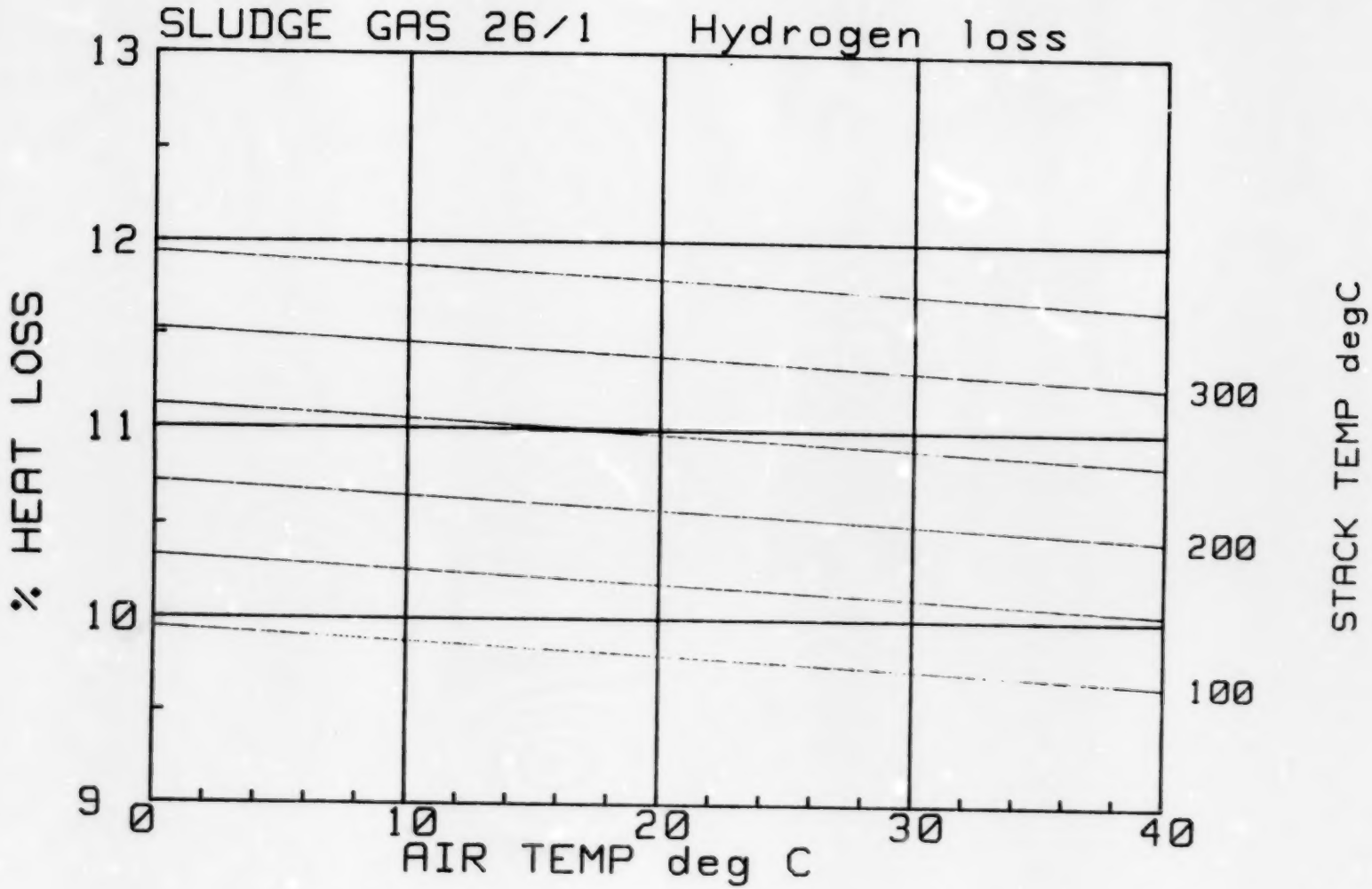
Therefore, stoichicmetric air requirement is:

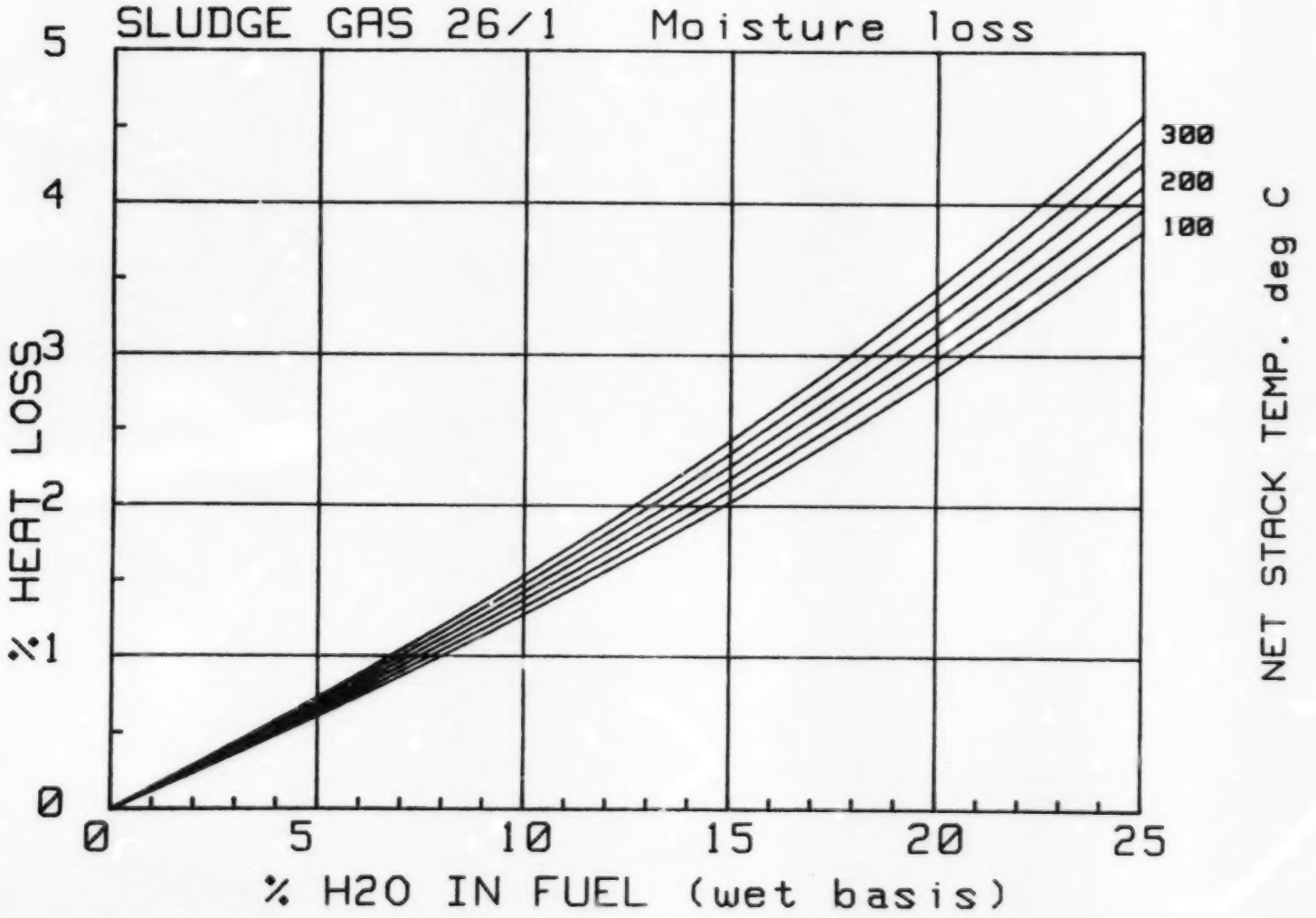
weight of fuel per 10^6 BTU = $\frac{10^6}{637.7}$ x 0.0699 = 109.6 lb.

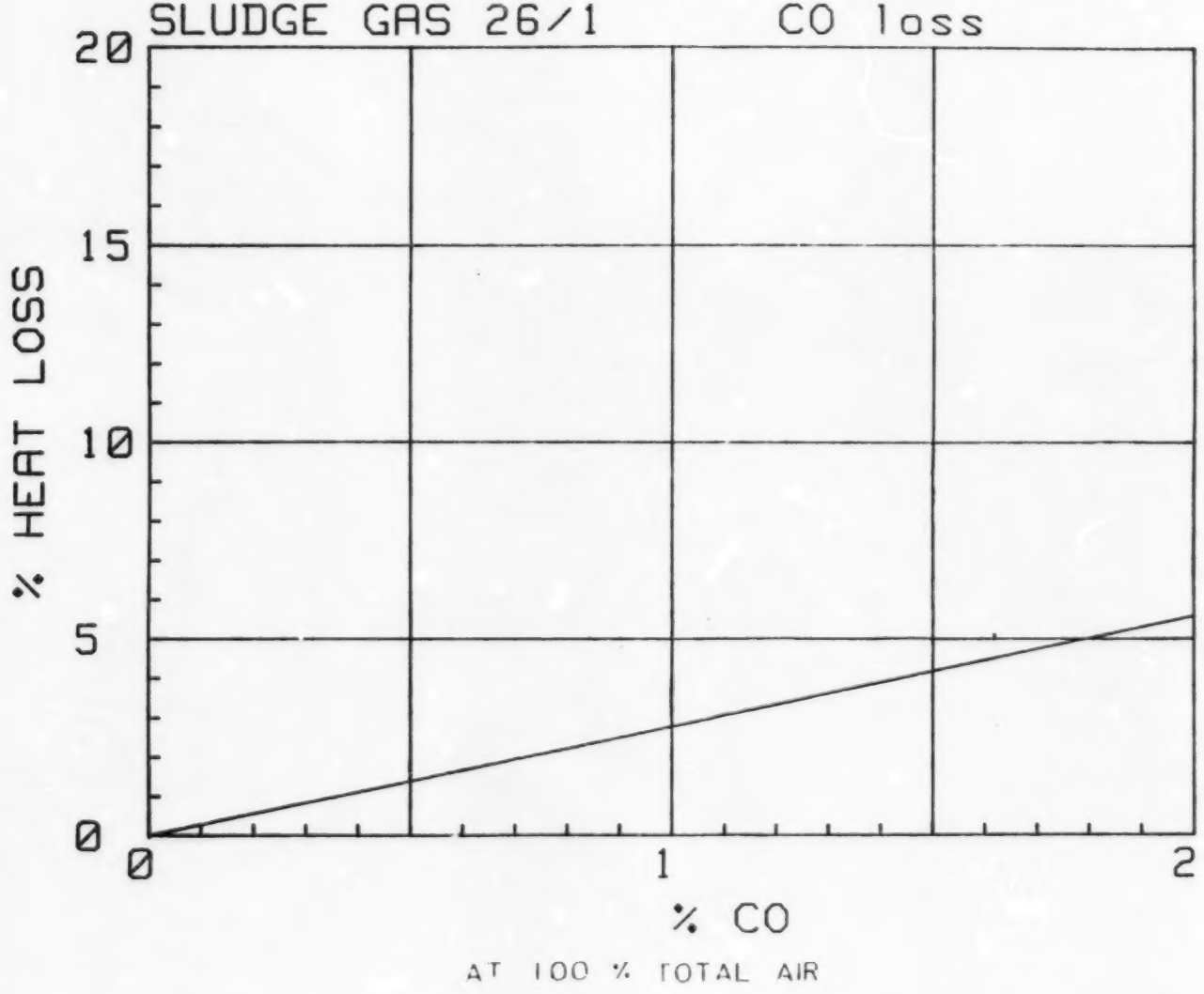

SLUDGE GAS 26/Volume base data
AIR&FLUE GAS VOL.(L/gm FUEL)
50
40
30
20
10
0
% CO2
18
17
16
15
14
13
12
11
10
9
8
CO2
O2
100
120
140
160
180
200
% COMBUSTION AIR
350
300
250
200
150
100
50
0
deg.C
AIR TEMP & NET STACK TEMP.
16
14
12
10
8
6
4
2
0
% O2

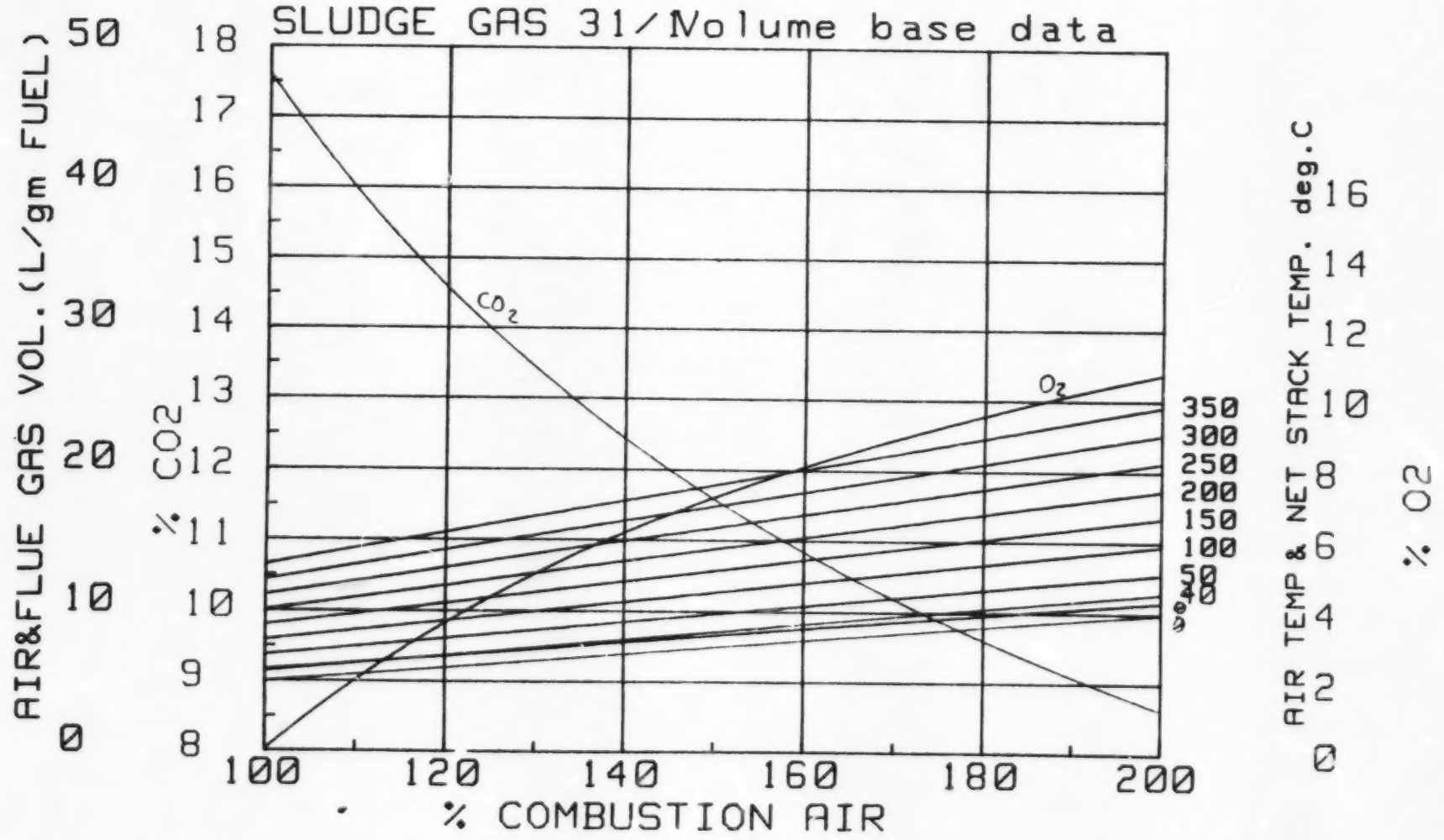

SLUDGE GAS 26/1 Weight base data
AIR & FLUE GAS (KG/KG FUEL)
25
23
21
19
17
15
13
11
9
7
5
% CO2
18
17
16
15
14
13
12
11
10
9
8
CO_2
O_2
tfgw
dry Flue gas
dry air
% O2
16
14
12
10
8
6
4
2
0
100
120
140
160
180
200
% COMBUSTION AIR

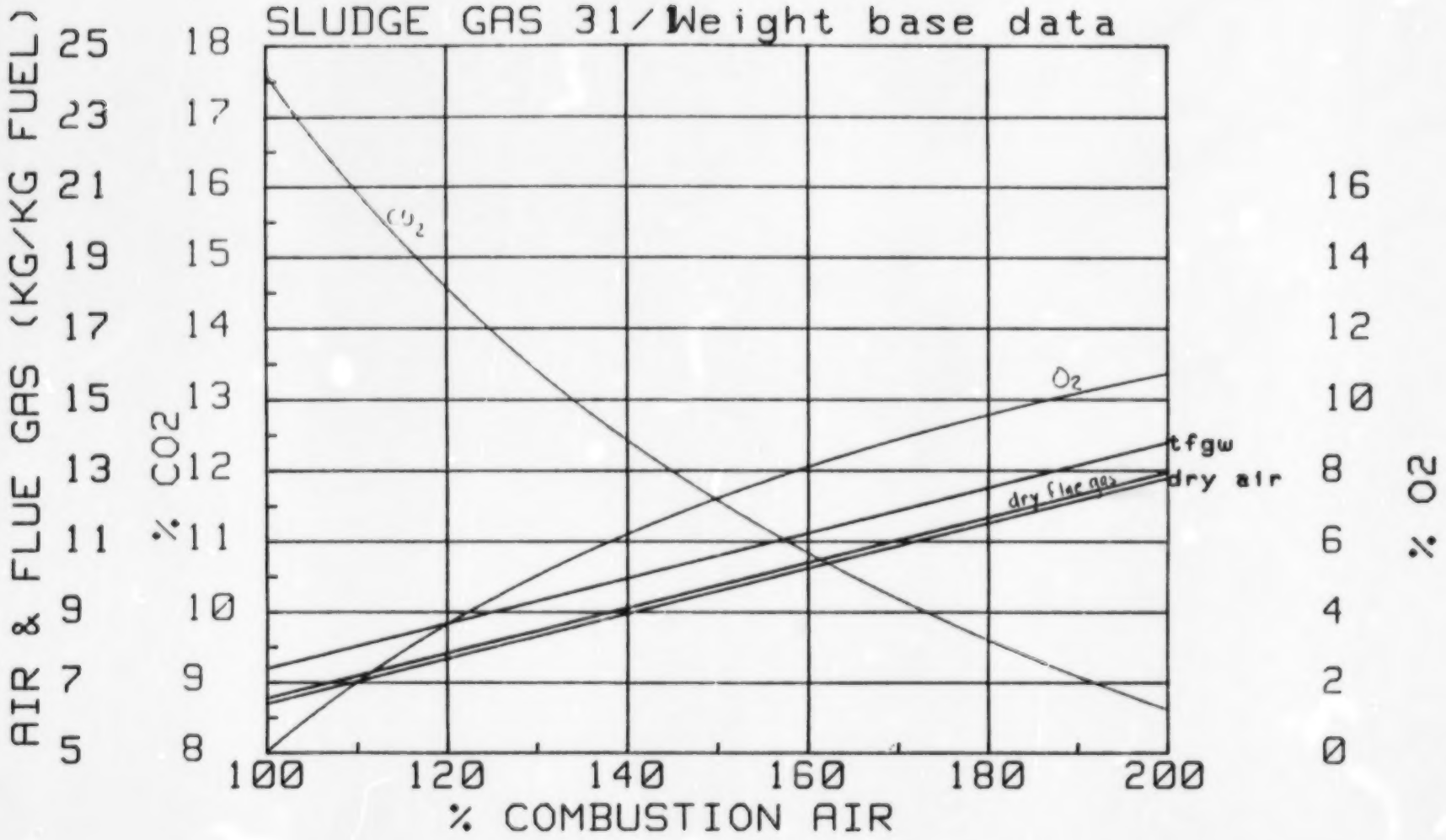

SLUDGE GAS 26/ Dry flue gas loss
% DRY FLUE GAS LOSS
40
36
32
28
24
20
16
12
8
4
0
% CO2
18
17
16
15
14
13
12
11
10
9
8
CO2
O2
350
300
250
200
150
100
50
NET STACK TEMP. deg.C
16
14
12
10
8
6
4
2
0
% O2
100
120
140
160
180
200
% COMBUSTION AIR

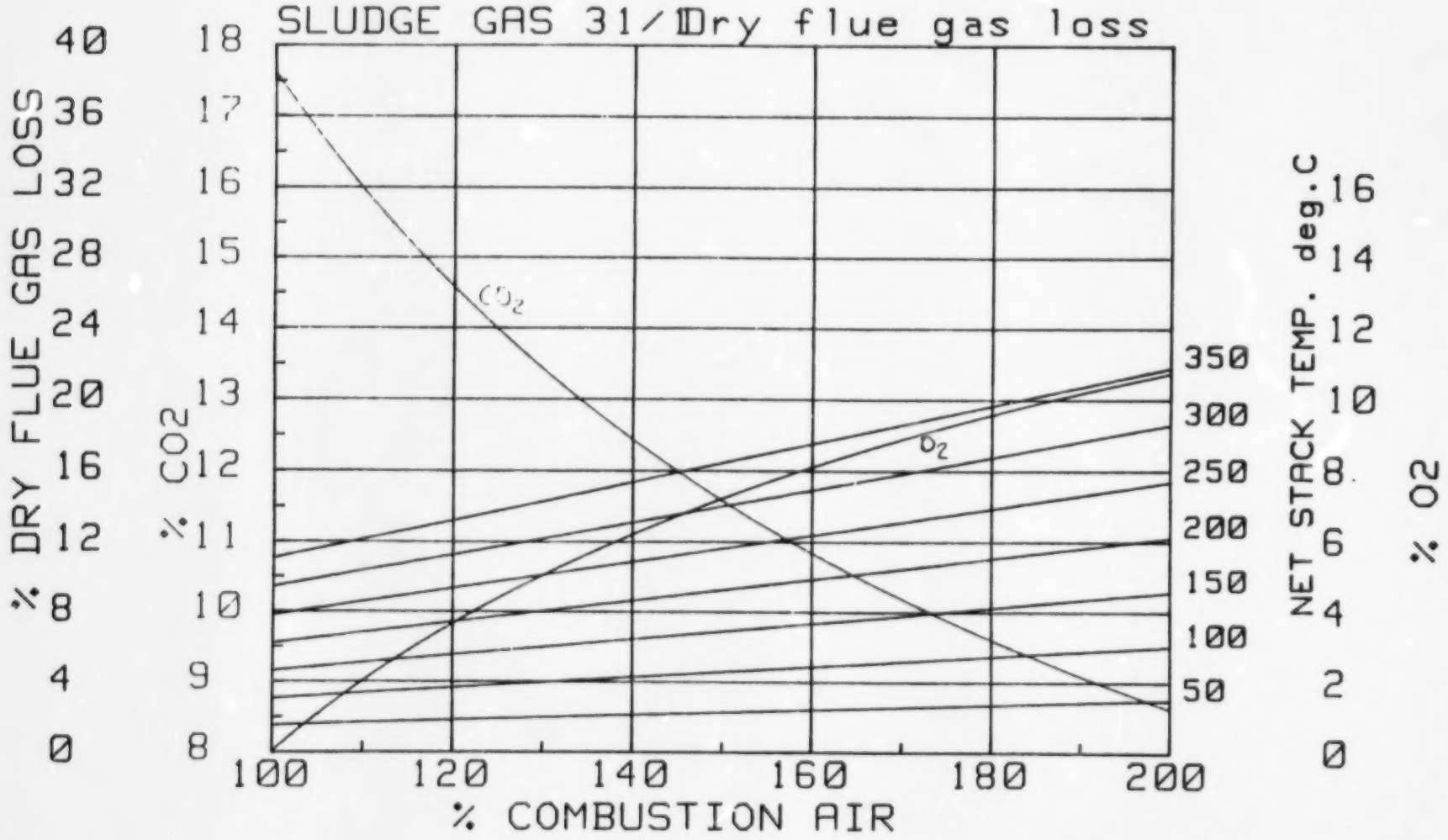

SLUDGE GAS 26/1 Hydrogen loss
% HEAT LOSS
13
12
11
10
9
0
10
20
30
40
AIR TEMP deg C
300
200
100
STACK TEMP degC

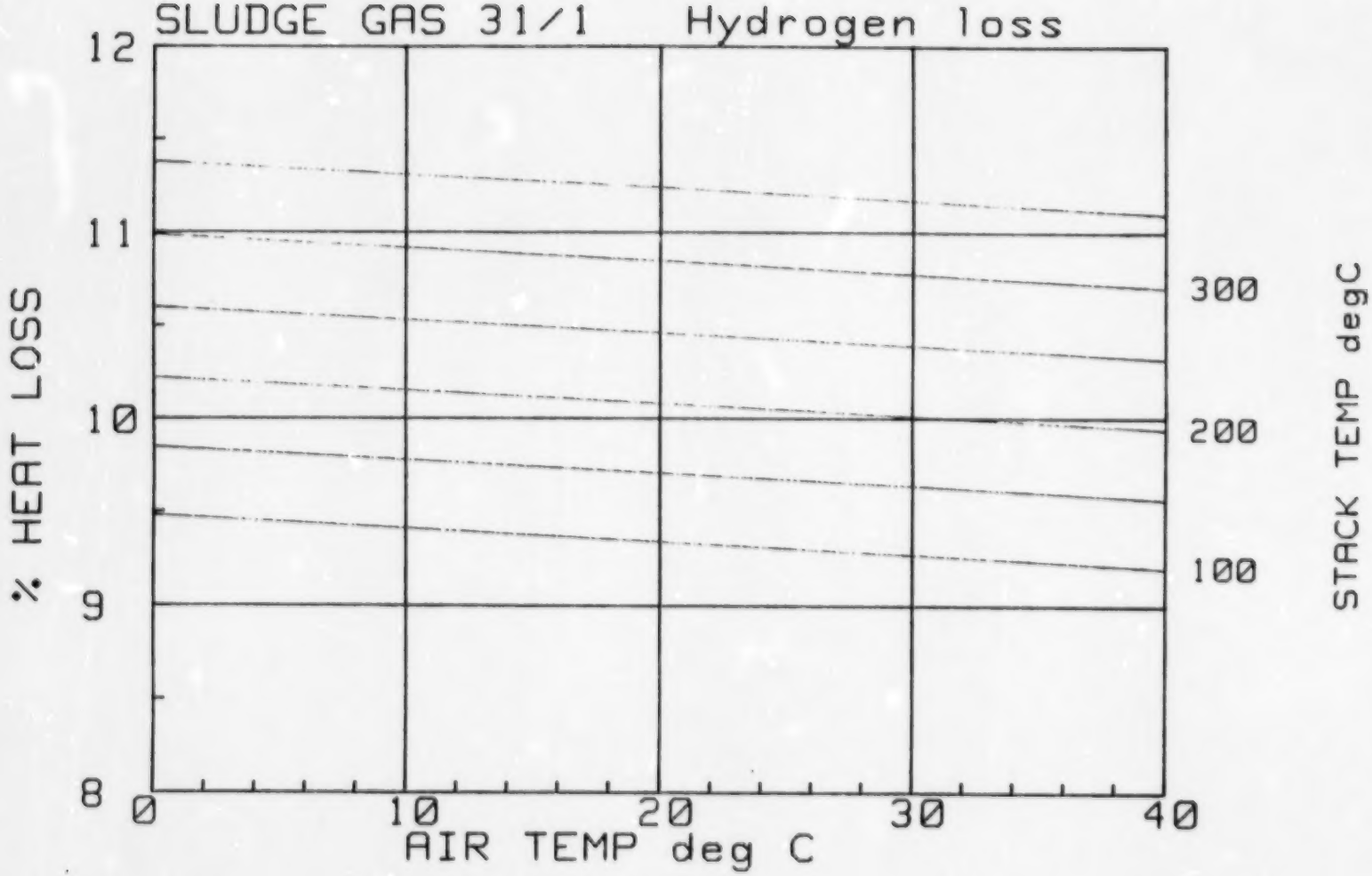

SLUDGE GAS 26/1 Moisture loss
% HEAT LOSS
0
1
2
3
4
5
0
5
10
15
20
25
% H2O IN FUEL (wet basis)
300
200
100
NET STACK TEMP. deg C

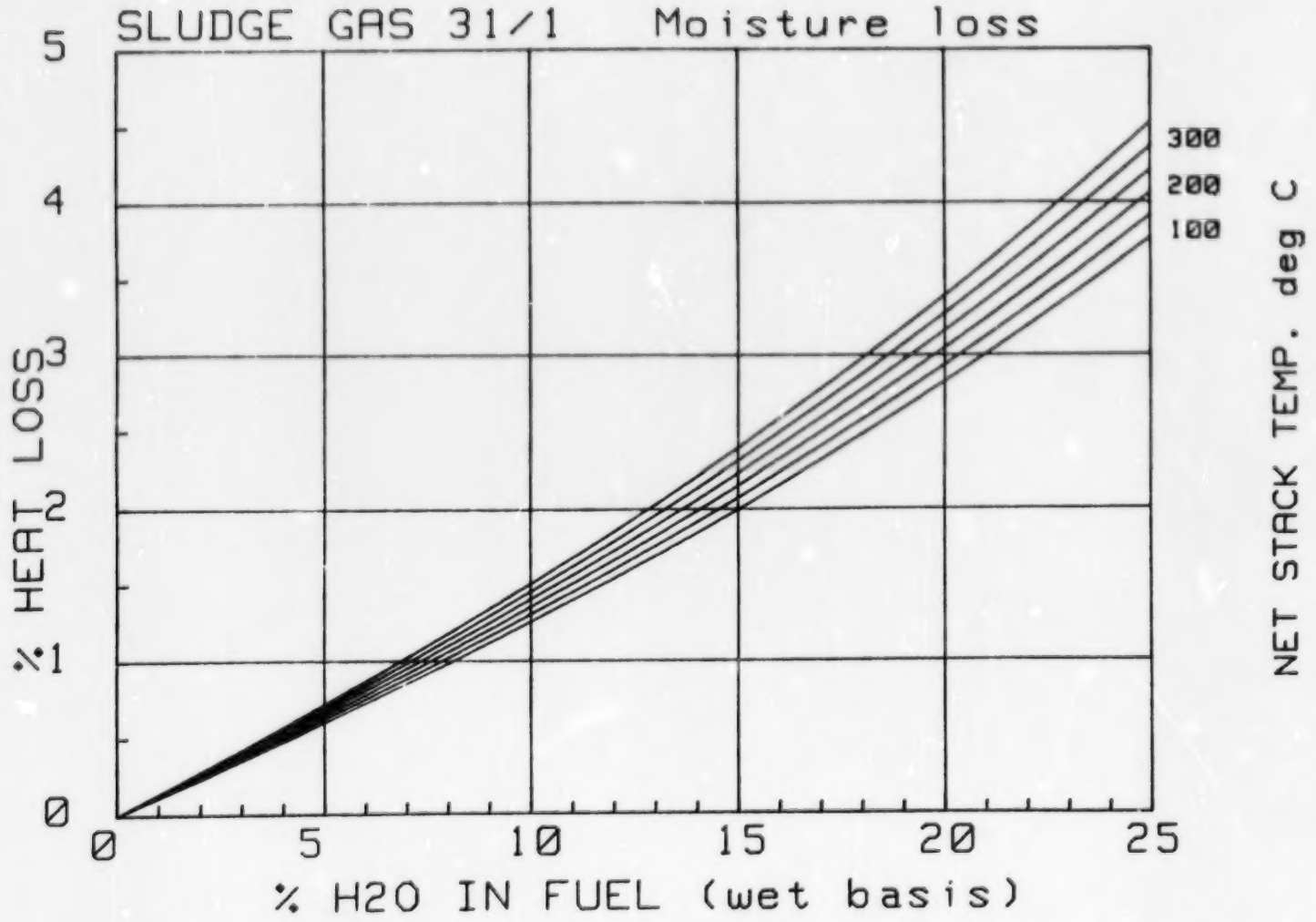

SLUDGE GAS 26/1
CO loss
20
15
10
5
0
% HEAT LOSS
0
1
2
% CO
AT 100 % TOTAL AIR

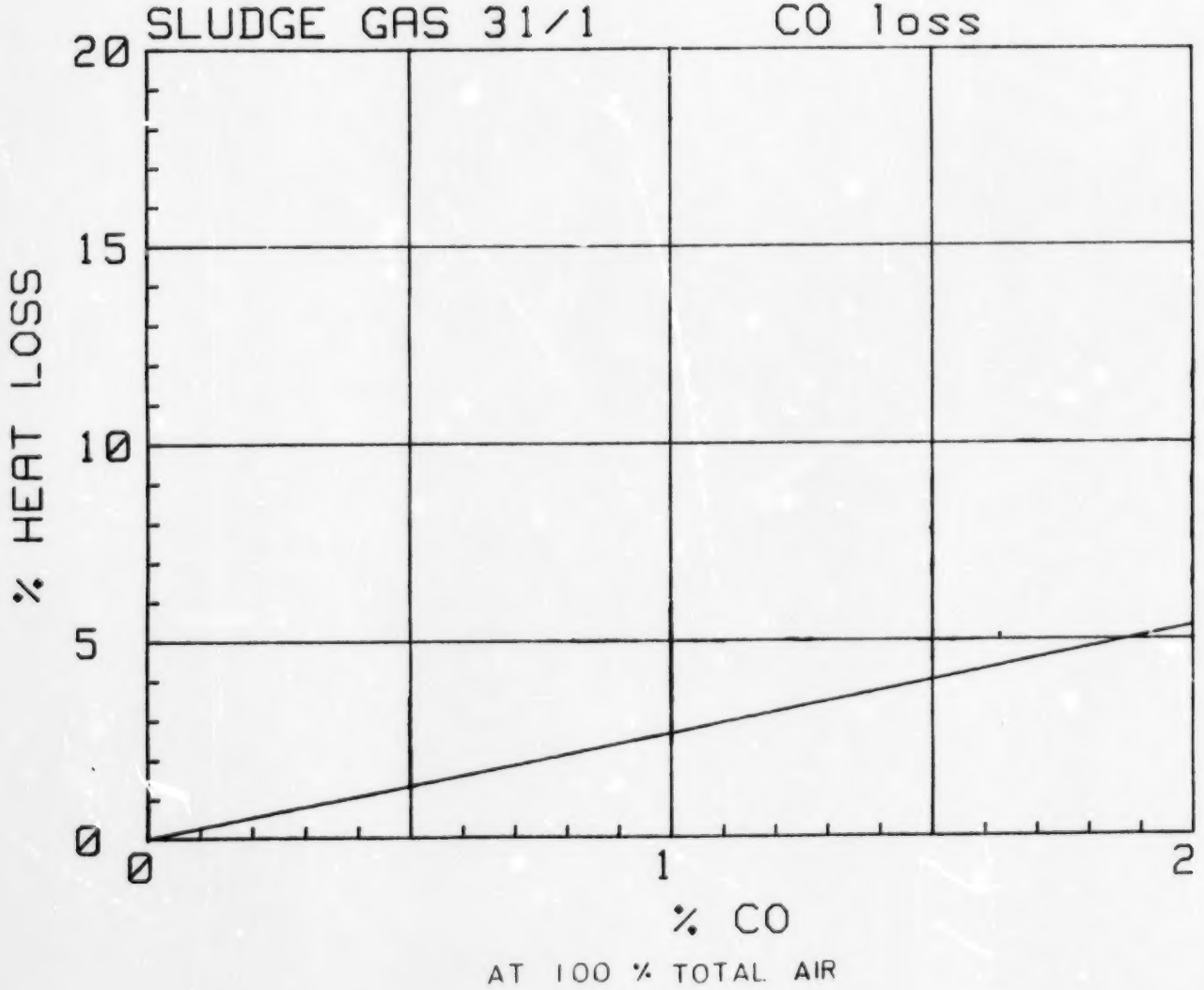

SLUDGE GAS 31/Volume base data
AIR&FLUE GAS VOL.(L/gm FUEL)
50
40
30
20
10
0
% CO2
18
17
16
15
14
13
12
11
10
9
8
CO_2
O_2
100
120
140
160
180
200
% COMBUSTION AIR
350
300
250
200
150
100
50
0
AIR TEMP & NET STACK TEMP. deg.C
16
14
12
10
8
6
4
2
0
% O2


SLUDGE GAS 31/1Weight base data
AIR & FLUE GAS (KG/KG FUEL)
% CO2
% O2
% COMBUSTION AIR
CO2
O2
tfgw
dry air
dry flue gas
25
23
21
19
17
15
13
11
9
7
5
18
17
16
15
14
13
12
11
10
9
8
16
14
12
10
8
6
4
2
0
100
120
140
160
180
200


SLUDGE GAS 31/1Dry flue gas loss
% DRY FLUE GAS LOSS
40
36
32
28
24
20
16
12
8
4
0
% CO2
18
17
16
15
14
13
12
11
10
9
8
CO2
O2
350
300
250
200
150
100
50
NET STACK TEMP. deg.C
16
14
12
10
8
6
4
2
0
% O2
100
120
140
160
180
200
% COMBUSTION AIR


SLUDGE GAS 31/1 Hydrogen loss
12
11
10
9
8
% HEAT LOSS
0
10
20
30
40
AIR TEMP deg C
300
200
100
STACK TEMP degC


SLUDGE GAS 31/1 Moisture loss
% HEAT LOSS
0
1
2
3
4
5
0
5
10
15
20
25
% H2O IN FUEL (wet basis)
300
200
100
NET STACK TEMP. deg C


SLUDGE GAS 31/1
CO loss
20
15
10
5
0
% HEAT LOSS
0
1
2
% CO
AT 100 % TOTAL AIR

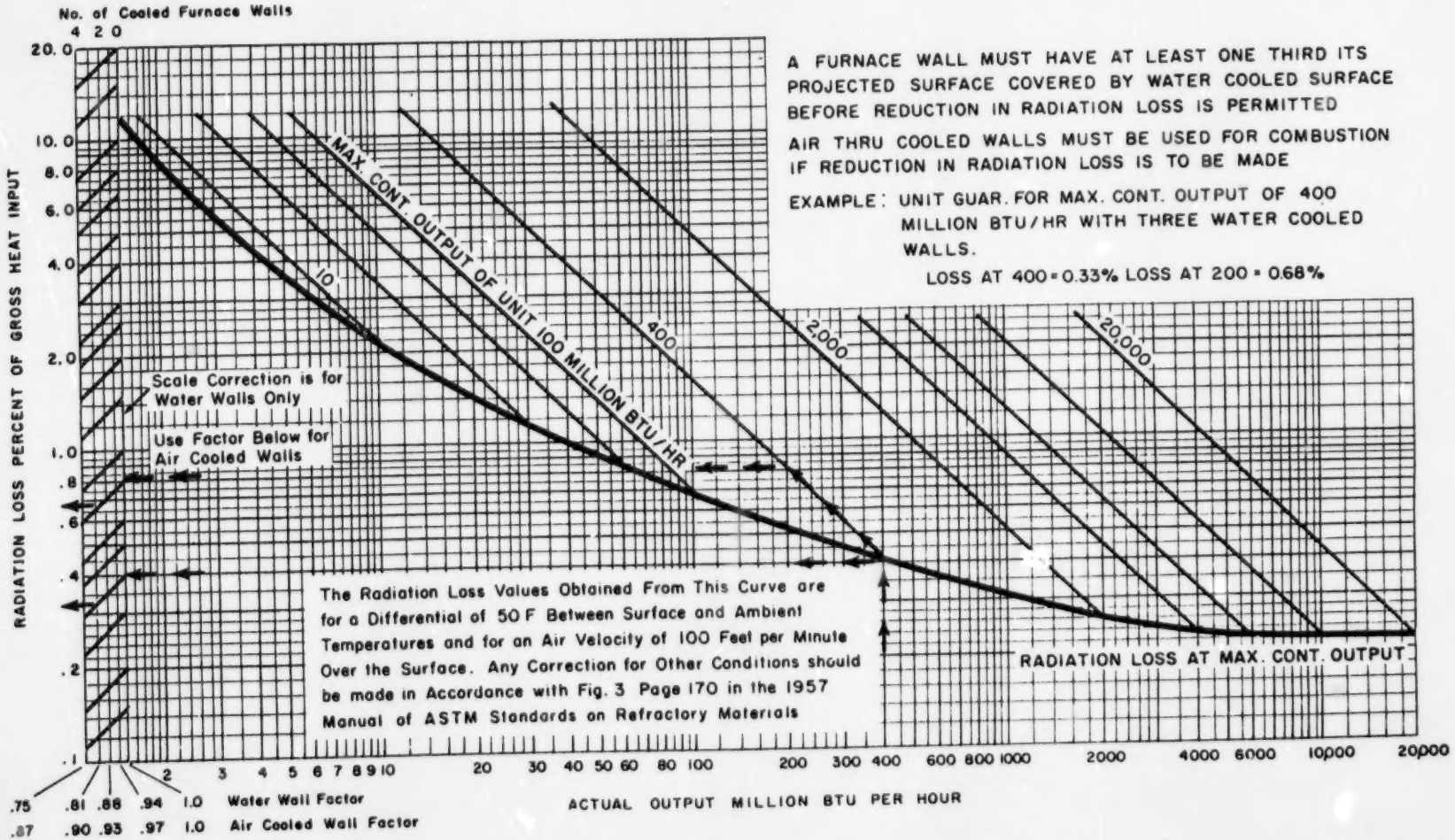

No. of Cooled Furnace Walls
4 2 0
RADIATION LOSS PERCENT OF GROSS HEAT INPUT
20.0
10.0
8.0
6.0
4.0
2.0
1.0
.8
.6
.4
.2
.1
A FURNACE WALL MUST HAVE AT LEAST ONE THIRD ITS PROJECTED SURFACE COVERED BY WATER COOLED SURFACE BEFORE REDUCTION IN RADIATION LOSS IS PERMITTED
AIR THRU COOLED WALLS MUST BE USED FOR COMBUSTION IF REDUCTION IN RADIATION LOSS IS TO BE MADE
EXAMPLE: UNIT GUAR. FOR MAX. CONT. OUTPUT OF 400 MILLION BTU/HR WITH THREE WATER COOLED WALLS.
LOSS AT 400 = 0.33% LOSS AT 200 = 0.68%
MAX. CONT. OUTPUT OF UNIT 100 MILLION BTU/HR
10
400
2,000
20,000
Scale Correction is for Water Walls Only
Use Factor Below for Air Cooled Walls
The Radiation Loss Values Obtained From This Curve are for a Differential of 50 F Between Surface and Ambient Temperatures and for an Air Velocity of 100 Feet per Minute Over the Surface. Any Correction for Other Conditions should be made in Accordance with Fig. 3 Page 170 in the 1957 Manual of ASTM Standards on Refractory Materials
RADIATION LOSS AT MAX. CONT. OUTPUT
2 3 4 5 6 7 8 9 10 20 30 40 50 60 80 100 200 300 400 600 800 1000 2000 4000 6000 10000 20000
ACTUAL OUTPUT MILLION BTU PER HOUR
.75 .81 .88 .94 1.0 Water Wall Factor
.87 .90 .93 .97 1.0 Air Cooled Wall Factor

FIGURE B. RADIATION AND CONVECTION HEAT LOSS CHART, ASSUMING EMISSIVITY = 0·95
PUBLISHED BY COURTESY OF THE AMERICAN BOILER MANUFACTURERS ASSOCIATION.

Combustible O_2 from air, if:

C	2.667 x 0.455 x 109.6	=	132.9 (CO_2)
H_2	8.000 x 0.096 x 109.6	=	84.1 (H_2O)
			217.0
less O_2 in gas	0.447 x 109.6	=	48.9
O_2 from air, lb/10^6 BTU		=	168.1
Associated N_2	= $\frac{76.85}{23.15}$ x 168.1	=	558.0
Dry Air, lb/10^6 BTU		=	726.1

Total air, %	100	150	200	225	235
Dry Air (lb/10^6 BTU)	726.1	1089.2	1452.2	1633.7	1706.3

Stoichicmetric products of combustion by weight

Dry products

CO_2	= 0.455 x 109.6 x $\frac{44.01}{12.01}$	=	182.7
N_2(air)		=	558.0
N_2(fuel)	= 0.002 x 109.6	=	0.2
Dry flue gas lb/10^6 BTU		=	740.9

Wet products

H_2O	= 0.096 x 109.6 x $\frac{18.02}{2.02}$	=	93.86

Total products = 834.76 lb/10^6 BTU

Products of Combustion and % CO_2, for 133% excess air

Dry products

CO_2	182.7 ÷ 44.01 x 359	= 1490.3
N_2	358.2 ÷ 28.01 x 350	= 7154.4
		8644.7

Wet products

H_2O	93.86 ÷ 18.02 x 359	= 1869.9
Total products		= 10514.6

for 133% excess air

O_2	1.33 x 168.1 ÷ 32 x 359	= 2508.2
N_2	1.33 x 558 ÷ 28.01 x 359	= 9511.8
		12020.0 cu.ft./10^6 BTU

additional dry products

CO_2 = 1490.3

O_2 = 2508.2

Dry Flue Gas Loss

$\frac{\text{lb dry gas}}{10^6 \text{ BTU}}$ = 965.7 + 740.9 = 1706.6

1706.6 x 0.24 x 374 x 100 ÷ 106 = 15.3%

Heat Loss due to Combustion of H_2

93.86 x (1089 - 62 + 0.46 x 435) x 100 ÷ 10^6 = 11.5%

Heat Loss due to CO/Combistibles

$\frac{CO}{CO_2+CO}$ x 10160 x $\frac{\text{lbc}}{10^6}$ = $\frac{0.02}{6.6+0.02}$ x 10160 x 132.9 = 0.4%

APPENDIX F

SPECIFICATIONS MODEL O-C

Measurement Range	Oxygen 0-25% Net Stack Temperature 0-999°F Computes Internally and displays Efficiency for natural gas and oil-fired units Carbon Dioxide 0-15.4% Excess Air 0-999% CO/Combustibles 0.00-0.10%
Sensitivity	Oxygen 0.1% Net Stack Temperature 1°F Efficiency 0.1% Carbon Dioxide 0.1% Excess Air 1%-3% over range 0-100% CO/Combustibles 0.01%
Calibration	Oxygen calibrates automatically on room air Zero values for oxygen and Net Temperature established automatically CO/Combustibles factory calibrated
Ambient Operating Temperature	32-120°F 0-50°C
Probe Length	Standard - 7½ inches (19 cm) Optional - up to 30 inches (76.2 cm)
Power	Six Nickel Cadmium D cells 115V power supply and built-in charge limiting circuitry
Weight	Complete - approximately 7½ pounds
Case Size	12½ in. W x 9 in D x 5½ in. H 31.75 cm W x 23 cm D x 14 cm H
Construction	Brushed anodized aluminum instrument chassis contained in a lightweight rugged black plastic case with metal fittings
Guarantee	Waranteed against faulty materials and workmanship for a period of six months.

APPENDIX F
BPH/SHAWINIGAN

DAY 1 - TEST #1 - 25% LOAD

JANUARY 26, 1984

TEST #	ITEM	UNITS	TIME (10 MINUTE INTERVALS)							AVERAGE	TOTAL
			8:56	9:06	9:16	9:26	9:36	9:46	9:56		
1	Steam	x100									
	Integrator	lbs	8858	8862	8866	8871	8876	8880	8886		2800
	Indicator	lbs/hr	2500	2700	2800	2500	2500	2200	3000	2600	
	Pressure	psig	85	85	85	85	85	85	85	85	
	Feedwater										
	Temp	°C	95.5	98	95.5	95.5	95.5	100	99.5	96.7	
	Sludge Gas	x1000									
	Volume	cu.ft.	4623	4626	4629.5	4633	4637	4640.5	4645		22 000
	Pressure	in H20	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	
	Room										
	DB	°C	16.5	16.5	16.5	16.5	16.5	16.5	16.5		
	WB	°C	9.0	8.0	8.0	9.0	9.0	8.0	9.0		
	Stack										
	DB (Net)	°C	191	190	190.5	189.3	189.3	188.5	187.5	189.6	
	CO2	%	6.5	7.0	6.5	6.5	6.5	6.5	6.5	6.6	
	O2	%	12.7	12.6	12.6	12.6	12.5	12.5	12.5	12.57	
	CO/Combust	%	0.05	0.05	0.05	0.01	0.00	0.00	0.00	0.02	
	Furnace Pressure	in H20 (+/-)	-.15	-.15	-.15	-.15	-.15	-.15	-.15	-0.15	

APPENDIX F
BPH/SHAWINIGAN

DAY 1 - TEST #2 - 75% LOAD

JANUARY 26, 1984

TEST #	ITEM	UNITS	TIME (10 MINUTE INTERVALS)							AVERAGE	TOTAL
			10:30	10:40	10:50	11:00	11:10	11:20	11:30		
2	Steam	x100									
	Integrator	lbs	8920	8933	8944	8956	8971	8981	8994		7400
	Indicator	lbs/hr	7000	7200	7500	7400	7200	7400	7500	7315	
	Pressure	psig	80	80	84	83	85	85	83	83	
	Feedwater										
	Temp	°C	103	102	100	101	102	103	101	101.5	
	Sludge Gas										
	Volume	cu.ft.	4661	4666	4670	4675	4681	4685	4689		28 000
	Pressure	in H20	46	46	46	46	46	46	46	46	
	Room										
	DB	°C	17	19	18.2	17	18.2	19	18.2		
	WB	°C	9	8	8.0	9	9.0	8	9.0		
	Stack										
	DB (Net)	°C	275.8	276	276	276	276	276	276	276	
	CO2	%	12.25	12.00	12.00	11.50	12.00	12.00	12.00	11.90	
	O2	%	6.9	6.8	6.9	6.7	6.8	6.8	6.8	6.8	
	CO/Combust	%	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.015	
	Furnace	in H20									
	Pressure	(+/-)	+0.1	+0.1	+0.1	+0.1	+0.1	+0.1	+0.1		

APPENDIX F
BFH/SHAWINIGAN

DAY 2 - TEST #1 - 50% LOAD

JANUARY 31, 1984

TEST #	ITEM	UNITS	TIME (10 MINUTE INTERVALS)							AVERAGE	TOTAL
			8:20	8:30	8:40	8:50	9:00	9:10	9:20		
1	Steam										
	Integrator	lbs	65124	65133	65143	65151	65161	65169	65178		5400
	Indicator	lbs/hr	5100	5200	5200	5200	5100	5100	5000	5130	
	Pressure	psig	83	83	83	83	84	84	85	83.6	
	Feedwater Temp	°C	98	98	101	97.5	97.5	97.5	97.5	98.5	
	Sludge Gas Volume	cu.ft.	7227	7231	7235	7238	7242	7246	7250		23 000
	Burner Manifold	in/H20	27	275	27	26.5	26.5	26.5	26.5	26.75	
	Room										
	DB	°C	21	21	21	21.5	21	21	21	21	
	WB	°C	11	11	11	11.0	11	11	11	11	
	Stack										
	DB (Net)	°C	238.5	239	236.5	236.5	235	235	236	236.5	
	CO2	%	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	
	O2	%	8.8	8.7	8.7	8.8	8.7	8.8	8.7	8.74	
	CO/Combust	%	0.00	0.01	0.02	0.02	0.00	0.01	0.01	0.01	
	Furnace Pressure	in H20 (+/-)	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	

APPENDIX F
BPH/SHAWINIGAN

DAY 2 - TEST #2 - 100% LOAD

JANUARY 31, 1984

TEST #	ITEM	UNITS	TIME (10 MINUTE INTERVALS)							AVERAGE	TOTAL
			10:15	10:25	10:40	10:50	11:00	11:10	11:20		
2	Steam										
	Integrator	lbsx100	65247	65262	65289	65303	65322	65340	65358		11 100
	Indicator	lbs/hr	9300	9900	9900	9900	9900	9900	9900	9900	
	Pressure	psig	78	78	80	80	80	78	78	78.85	
	Feedwater										
	Temp	°C	101	102	96	98	100.5	101.5	99	99.5	
	Sludge Gas										
	Volume	cu.ft.	7269	7273	7279	7282.5	7287	7291	7295		26 000
	Burner Manifold		76	78.5	79	79	79	79	79	78.5	
	Room										
	DB	°C	22.0	21.5	21	21	21	21	21.5	21	
	WB	°C	12.5	12.0	12	12	12	12	12.0	12	
	Stack										
	DB (Net)	°C	285	288.5	290	290.5	290.5	290.5	290.5	289.5	
	CO2	%	14	14	14	14	14	14	14	14.0	
	O2	%	4.0	3.8	3.9	3.9	4.0	3.9	3.9	3.9	
	CO/Combust	%	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
	Furnace Pressure	in H20 (+/-)	+0.2	+0.2	+0.2	+0.2	+0.2	+0.2	+0.2	+0.2	

POOR

QUALITY

ORIGINAL